**South Carolina Public Service Commission**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Composite Appendix VS-3**

**Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Responses to Office of Regulatory Staff Data Requests 7-8, 7-16, 7-18, and 7-28**
**and**
**Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Response to Carolina Clean Energy Business Association's First Set of Interrogatories**

**Duke Energy Carolinas, LLC's**
**and**
**Duke Energy Progress, LLC's**
**Response to**
**SC Office of Regulatory Staff**
**Data Request No. 7-8**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Date of Request:** **September 8, 2021**
**Date of Response:** **September 22, 2021**

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☒ **NOT CONFIDENTIAL**

***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Mike Quinto, Lead Engineer, and was provided to the SC Office of Regulatory Staff under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

*To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.*

**Request**:

7-8 See page 15 of the DEC Modified IRP. What are the biggest issues that could make retirement of 10,000 megawatts ("MW") of coal resources in an 8-year period challenging?

**Response**:

There are several issues that make the retirement of 10,000 MW of coal resources in an 8-year period challenging including primarily the ability to site, permit, and construct the needed firm replacement capacity in this timeline. The development timeline for reliable replacement generation project can range from 3 to 6 years. Additional factors include the timeline for stakeholder engagement and environmental permitting, along with the CPCN process for approval for this relatively large number of units to safely and reliably replace the 10,000 MW of coal capacity. Furthermore, multiple projects progressing at the same time can cause labor and supply chain issues in the construction process and overall is a large task for entities involved in the Engineering, Procurement and Construction (EPC) processes. As stated in the SC Modified IRP, the selection of C1 is directional in nature recognizing that the exact timing and type of replacement generation will evolve in future IRPs as market conditions and energy policy evolves.

**Duke Energy Carolinas, LLC's**
**and**
**Duke Energy Progress, LLC's**
**Response to**
**SC Office of Regulatory Staff**
**Data Request No. 7-16**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

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The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Glen Snider, Director of Carolinas Integrated Resource Planning and Analytics, and was provided to the SC Office of Regulatory Staff under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

*To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.*

**Request**:

7-16 See page 23 of the DEC Modified IRP. Is the Company claiming it does not recommend that portfolio C1 be used for Public Utility Regulatory Policies Act ("PURPA") and Energy Efficiency/Demand Side Management ("EE/DSM") evaluations? Please clarify what the Company believes should be used in those proceedings. Please provide specific examples of any other times when the Company would prefer to use other portfolios as the Appropriate plan, which portfolio it would propose to use instead, and why the proposed portfolio would be a better selection in that case than C1.

**Response**:

With respect to the establishment of PURPA QF rates, this statement is based on Act 62's mandate that the Commission establish avoided cost rates that are consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations. FERC has been clear that a state may not set avoided cost rates by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities. *Southern Cal. Ed.*, 71 FERC P 61,269, 62,080 (June 2, 1995). This means that avoided cost rates should be established as a function of actual costs projected to be avoided based on existing markets, rules and regulations. To the extent carbon legislation has not yet been enacted at the state or federal level, it would not be appropriate for customers to pay for "avoided carbon" costs in QF contracts prior to regulation being enacted that places a real cost on carbon. Portfolio A1 is developed without an assumption of carbon regulation and as such forms a more appropriate starting point for the development of avoided cost rates. Of note, avoided cost rates are not established directly from any portfolio in the IRP but rather from an adjusted portfolio that removes non-designated QF resources from the IRP portfolio prior to calculating AC avoided cost rates. Once a portfolio is established the inputs to that portfolio are then updated based on the known conditions at the time the rates are developed. To the extent carbon legislation has not been enacted prior to the rate calculation it is not explicitly or implicitly included in the production cost model used to develop rates. Other examples of where the Commission may choose to use another portfolio would be case specific and dependent on the facts, circumstances and intended use of the portfolio in that particular proceeding. It is premature to provide specific examples but as a more general example for illustrative purposes, in the context of a CECPCN filing the PSC may want to view the economic impact of a new resource addition from the vantage of a couple portfolios in the IRP. Such a view could provide insights into the value of a particular asset in an uncertain energy future. At this time the Company is not suggesting such an approach but rather gives this example as an illustration of the value of presenting multiple portfolios in the IRP.

**Duke Energy Carolinas, LLC's**
**and**
**Duke Energy Progress, LLC's**
**Response to**
**SC Office of Regulatory Staff**
**Data Request No. 7-18**

**Docket No. 2019-224-E**
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The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Matthew Kalemba, Director DET Planning and Forecasting, and was provided to the SC Office of Regulatory Staff under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

*To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.*

**Request**:

7-18 See page 27 of the DEC Modified IRP that states, "the Companies divided the annual amount of utility cost-of-service (COS) solar and $38/MWh third-party Purchase Power Agreement ("PPA") solar that can be connected to 375 MW each (50 percent of the 750 MW solar interconnection limit)." Please provide the step-by-step process by which the Company performed these modeling steps. Provide any workpapers that were used in performing these steps in Excel format, with all formulae attached, and be clear how these steps were performed with regard to optimization modeling, and forcing in resources versus allowing optimal selections to be made. In other words, were these steps performed such that inputs into the optimization model were affected, did these steps result in resources being forced in to the model, etc. Be very clear about what was done to model what was described.

**Response**:

As was the case in the September 2020 IRP filing, there are two ways in which solar resources can enter a portfolio. First, solar can be "forced in" as an input to the model; and second, solar can be economically selected by the model above the input amount of solar. The amount of solar "forced" into the model was the same in the SC Modified IRP filing as the amount included in the September 2020 IRP filing. As described on page 33 of the DEC SC Modified IRP, the Companies input solar into the model that "is represented as either designated, mandated, or undesignated." The designated and mandated solar represents solar that has executed contracts (designated) or capacity that is not yet under contract but is required through renewable energy programs driven by existing law (mandated). Undesignated is additional solar capacity that is assumed to materialize from the interconnection queues above and beyond the capacity that is classified as "mandated."

In addition to the solar that was "forced in", the capacity expansion model (SO) was allowed to select incremental solar resources up to a total (forced in + economically selected) of 750 MW annually, split between DEC (450 MW) and DEP (300 MW). The model was allowed to select a combination of $38/MWh PPA solar, as well as, utility cost of service (COS) solar. Importantly, since SO does not allow for MW constraints, the total number of solar units was used in the model to represent the 750 MW interconnection limit. In most years, the availability of solar units for the model to select from was split evenly (50/50) between $38/MWh PPA solar and utility COS solar. However, there were some years where, due to the interconnection constraint, there were an odd number of units to select from. In those years, the Companies assumed there were more PPA options to select from rather than utility COS units. The workpapers that were used to determine how much of each solar resource could be selected is included in response to ORS 7-20.

There were several reasons why the model was not allowed to select only $38 solar PPA options. First, it is likely that if $38/MWh PPAs are available, they would be included in the "undesignated" category as those MWs are likely to include $38/MWh PPA resources. Therefore, if those PPAs are available in the "undesignated" category, that would limit the amount of $38/MWh resources allowed to be economically selected. Second, given the depth of market issue the Companies raised for these lower cost PPA options, it was reasonable to allow the model to select alternatively priced options to better understand the range of prices that solar was valued under. In all years of the preferred portfolio, except 2030, the model selected the maximum amount of solar units available up to the 750 MW limit regardless of price assumptions.

**Duke Energy Carolinas, LLC's**
**and**
**Duke Energy Progress, LLC's**
**Response to**
**SC Office of Regulatory Staff**
**Data Request No. 7-28**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

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The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Mike Quinto, Lead Engineer, and, Matthew Kalemba, Director DET Planning and Forecasting, and was provided to the SC Office of Regulatory Staff under my supervision.

Heather Shirley Smith
Deputy General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

*To the extent information differs for DEC and DEP, provide the different information, otherwise please note the information provided is the same for both.*

**Request**:

7-28 With regard to energy storage modeling, the Company states at page 45 of the DEC Modified IRP, "As discussed in the energy storage assumption section, the two sets of economically optimized portfolios selected batteries using different battery cost assumptions. However, when comparing the financial results of the portfolios, a consistent battery cost was used for all portfolios, regardless if the portfolio was optimized with the base or alternate battery costs. This consistency eliminates portfolio cost variability due to different technology cost assumptions."

a) Please confirm that the A1, B1, and C1 cases all used the Company's battery storage cost assumptions as developed in the 2020 IRP for both optimization and final cost reporting.

b) Please confirm that for optimization purposes in the A2, B2, and C2 cases, the Company used the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") low cost assumptions, but for cost reporting it used the costs that were used in the A1, B1 and C1 studies. If this is not true please correct, but if it is true, please provide more information on why the decision was made to use the same costs as in the A1, B1, and C1 studies. Was there something about the modeling results that led to this change in reporting costs?

c) What is different about battery storage modeling cases versus solar cases that required switching out the costs for reporting purposes. In other words, like battery storage the Company ran different solar cases with $34, $38 and $40/MWh costs, but did not swap out to use a consistent cost for reporting in those cases.

d) On page 55 of the DEC Modified IRP the Company mentions that it will continue to evaluate the possibility that battery storage resources could "provide more benefits to the system that could lead to earlier economic adoption than shown in these portfolios," beyond bulk system benefits like capacity value and energy arbitrage. Please describe what other potential benefits the Company is evaluating, and how it is quantifying those benefits.

**Response**:

a) The development of Portfolios A1 and B1 used the Companies' battery storage cost assumptions consistent with the price used in the original 2020 IRP filling. The PVRRs presented throughout the IRP use the Companies' assumed battery costs used in the original 2020 IRP filing, unless otherwise noted. Portfolio C1 did not reoptimize the selection of batteries, but used the amount of economically selected of batteries from B1 and accelerated those to facilitate the retirement of Mayo Station for DEP. No batteries were economic in DEC in Portfolio B1, so no economically selected battery replacements were carried forward from portfolio B1 to Portfolio C1.

b) The development of Portfolios A2 and B2 used the NREL ATB Advanced Case (low cost assumptions) for battery storage cost assumptions. Because Portfolio B2 had more economic battery replacements relative to B1, Portfolio C2 used the amount of batteries economically selected in Portfolio B2 and replaced additional CTs in this portfolio relative to the battery replacements for Portfolio C1. After the development of the portfolios, the Companies used their base battery cost forecast for the PVRR in IRP's scenario analysis of all SC Supplemental Portfolios regardless of optimization. For portfolio comparison purposes, it is improper to compare cost performance of portfolios with different technology costs for the same resources. Doing so would create an inconsistency, as resource costs would naturally be the same in all portfolios. Said another way, the Companies would not pay a higher technology cost, if the lower costs actually do materialize. The methodology allows for variances in the volumes of BESS in each of the portfolios but puts the per unit cost of the BESS resource on even comparison throughout all other portfolios.

c) The same battery cost is used in the portfolio analysis for comparison purposes because only one future, with one set of technology cost assumptions can materialize so comparing portfolios that have the same technology with differing costs is of limited utility. Sensitivity analysis on the other hand looks more broadly at possible futures for individual inputs. Sensitivity analysis looks at not only how will resources be optimized under different cost trajectories, but also what is the potential opportunity cost for each of these possible different futures. For example in DEP, if solar PPA was available at \$40/MWh opposed to \$38/MWh as the base assumption, under the Company's base gas and battery costs, the selection of PPA solar would be delayed from 2024 to 2025, total amount of economically selected solar would be reduced by 300 MW, and in doing so would results in a savings of \$0.3 B compared to Portfolio B1 with the more economic selection of resources and corresponding portfolio utilization, commitment and dispatch.

d) There are variety of other potential benefits that could potentially be combined to create shared value streams for battery storage. Some of these potential benefits include:

- Using battery storage to provide ancillary requirements such as regulating reserves, contingency reserves, and balancing reserves. The Company is investigating quantifying these benefits through a variety of production cost modeling exercises.
- Providing black start service to the grid if a storage option was identified with a lower total cost than other traditional alternatives.
- Transmission and Distribution Capacity (or deferral) benefits where energy storage would be used to delay the need to build, replace, upgrade or operate traditional transmission or distribution if a lower cost option was identified.

Generally, these, and other potential battery benefits, are being evaluated as part of the Company's ISOP framework and further detail of the quantification of these benefits are expected to be provided in the 2022 comprehensive IRP filing.

**BEFORE**

**THE PUBLIC SERVICE COMMISSION OF**

**SOUTH CAROLINA**

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

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| In the Matter of:<br><br>South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC | **DUKE ENERGY CAROLINAS, LLC'S AND DUKE ENERGY PROGRESS, LLC'S RESPONSE TO CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION'S FIRST SET OF INTERROGATORIES** |

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP," together with DEC, the "Companies"), by and through counsel, pursuant to Rules 103-833(B), 103-833(C) and 103-835 of the Rules of Practice and Procedure of the South Carolina Public Service Commission and the South Carolina Rules of Civil Procedure, hereby respond to Intervenor, Carolinas Clean Energy Business Association's ("CCEBA") First Interrogatories as follows:

**<u>RESPONSES TO FIRST INTERROGATORIES</u>**

1. Please refer to Public Service Commission of South Carolina Order 2021-447. Ordering paragraph 6 specifies a number of modifications that the Companies should make to their ELCC methodologies. Please indicate for each subpart of Ordering Paragraph 6 how the Companies incorporated the directive into the Modified IRPs. Also, please indicate the updated ELCC values that were used in the Modified IRP modeling.

**<u>RESPONSE</u>**: The Companies interpret the requirements of Ordering Paragraph 6 as applying to the IRP Update and not the SC Modified IRP. This understanding is based on the Commission's instruction, on page 45 of Order No. 221-447, to use a capacity expansion model that is capable of single-step optimization and to develop and use an ELCC surface in the Companies' next IRP Updates. See below for relevant discussion:

> Duke also did not calculate the synergistic effects of solar and storage and map those results onto a surface for use in single-step capacity expansion modeling that would allow these resources to compete on equal footing with resources like gas. To correct this error, the Commission directs Duke to use a capacity expansion model in developing its next IRP Update that is capable of the single-step optimization recommended by Witness Olson. In addition to using single-step optimization, Duke shall develop and utilize an ELCC surface as recommended by Witness Olson. Order No. 221-447, at 45 (emphasis added).

Please also refer to the Companies' response to ORS AIR 7-39.

2. Please confirm whether the Companies utilized the same modeling software in preparing their Modified IRPs as they did in preparing their original IRP. If denied, please indicate what modeling software was used in preparing the Modified IRPs.

**RESPONSE**: The Companies used the same modeling software in preparing their SC Modified IRPs as they did in preparing the originally-filed 2020 IRPs. Specifically, the Companies used System Optimizer for capacity expansion modeling and PROSYM for production cost modeling.

3. **Please refer to Figure 2-B,** "DEC & DEP Portfolio C1 Incremental Solar Additions" in both Modified IRPs.

a. For both DEC and DEP, provide a breakdown of annual solar additions by policy directive (e.g. x MW from CPRE, x MW from HB589, etc.).

b. For capacity listed as "Undesignated Util COS Solar", please provide the justification or basis for utility ownership of this capacity for each year.

c. Please explain why some years exceed the 750 MW interconnection limit that was modeled.

d. Do the Companies believe they will be able to interconnect more than 750 MW per year as indicated in Figure 2-B?

e. Please confirm whether the 750 MW interconnection limit was binding on the quantity of solar that was added in a given year, and that absent this limit (or if the limit were increased) whether more solar would have been selected by the model.

f. Please confirm that the model always selected the maximum allowable quantity of $38/MWh PPA solar.

g. Please confirm whether the model always selected the $38/MWh PPA option before it selected utility-owned solar.

**<u>RESPONSE</u>**:

a. Please see the attached file CCEBA_DR_1-3A.xlsx.

CCEBA_DR_1-3A.xlsx

b. There are two cost options for solar that is economically selected in the SC Modified IRP: (1) $38/MWh PPA solar; and (2) Utility cost-of-service ("COS") solar. As discussed on page 27 of the DEC SC Modified IRP, the Companies divided the annual amount of utility COS solar and $38/MWh third-party PPA solar that can be connected to 375 MW each (50% of the 750 MW solar interconnection limit). Because of this split, and because the model incrementally selected $38/MWh solar, the forced-in "undesignated" solar could not be 100% $38/MWh solar. The remaining solar that made up the forced-in "undesignated" solar was labeled as Utility COS solar because that is the only other solar option included in the IRP.

c. In some years, the total nameplate capacity of solar exceeds 750 MW. This occurs because the model selects solar in 75 MW increments, and if, at any point, the amount of solar is less than the interconnect limit, the model can select an additional unit even if selecting that solar causes the model to exceed the constraint. A complicating factor is that the 750 MW constraint is a DEC+DEP constraint, but DEC and DEP are modeled separately in the capacity expansion model, so the capacity constraint was split 450 MW in DEC and 300 MW in DEP. However, there are some years (2026 – 2028) where DEC could select an additional unit above the 450 MW limit because DEP was not selecting up to the maximum allowed solar. If that additional flexibility was not added in DEC, then the total 750 MW constraint would not have been reached.

d. Please see the Companies' response to CCEBA DR 1-3(c) for an explanation of why some years exceed the 750 MW/year interconnection limit in the Modified IRP. Given that the Companies' historical interconnection average is approximately 500 MW, the Companies are uncertain of their ability to interconnect 750 MW of new solar per year, much less volumes beyond 750 MW. The Companies do anticipate that queue reform will improve the efficiency of studying interconnection requests and will continue to refine these assumptions in future IRPs.

e. The 750 MW (400 MW DEC / 350 MW DEP) interconnection constraint was not limiting in all years. For DEC in 2023, an additional 75 MW unit could have been selected, but was not selected by the model. For DEP in 2026-2029, an additional 75 MW unit could have been selected, but was not selected by the model.

f. Confirmed. The model always selected the maximum allowable quantity of $38/MWh solar.

g. Yes, the model always selected the $38/MWh PPA option before selecting utility-owned solar based on the inputs to the capacity expansion model, which did not include factors such as the cost of the replacement facility (either new PPA contract or alternative solar resource) at the end of the 20-year PPA term.

4. Please provide the Levelized Cost of Energy and revenue requirement per MWh of utility-owned solar by year for each year modeled in the Modified IRPs.

**RESPONSE**: The Levelized Cost of Energy ("LCOE") for resources is not calculated or used as part of the selection criteria in IRP modeling. Resources are selected based on their levelized revenue requirements. The levelized revenue requirements for the Utility COS solar are included in response to ORS AIR 7-2b. Please refer to the following files:

ORS AIR 7-2b - DEC New Gen Capital PVRR - Confidential.xls
ORS AIR 7-2b - DEP New Gen Capital PVRR - Confidential.xls.

5. Why did the Companies not create a D2, E2, and F2 portfolio consistent with the Commission's directives to use a modified natural gas and battery cost forecast?

**RESPONSE**: Portfolios D, E and F were illustrative in nature and designed to show different trajectories for CO2 reduction. These portfolios were also identified as heavily dependent on technology and policy advancements, and they forced emergent carbon-free technologies into the model to illustrate the impact such technologies would have on carbon reductions. As such, these emergent technologies were not economically selected by the model. In light of the Commission's directive that the Companies must select a preferred portfolio, the Companies' Modified IRPs focused on comprehensively analyzing Portfolios A, B and C under the Commission-directed modified assumptions, as these Portfolios had greater dependence on economically selected technologies that are readily available today.

6. Please refer to Commission Order 2021-447, Ordering Paragraphs 10 and 16. Given the specific directive from the Commission to use updated natural gas and battery cost forecasts, why did Duke Energy select Portfolio C1, which was based on the Companies' original natural gas and battery cost forecast? Please explain how this selection, rather than selecting Portfolio C2, is consistent with Ordering Paragraphs 10 and 16 of Commission Order 2021-447.

**RESPONSE**: The Companies Modified IRPs provide Supplemental Portfolios and analysis that fully comply with the requirements of Order No. 2021-447, including incorporating the alternative modeling assumptions identified in Ordering Paragraphs 10 and 16. The Order at page 85 directed the Companies to select a preferred resource portfolio. The Companies selected Portfolio C1 as the preferred resource portfolio for the reasons stated in the Modified IRPs.

7. What is the basis for limiting third-party PPAs to only 50% of solar additions? Please indicate with specificity where the Commission approved this limit in Order 2021-447, or any other policy justification for this limit.

**RESPONSE**: Please see the Companies' response to ORS AIR 7-17 for an explanation as to why the Companies believe it is not prudent to rely solely on third-party solar for all solar additions. Order 2021-447 does not specify the amount of third-party solar that the Companies should include in the IRP.

8. Separately, for both DEC and DEP, please provide the MW of capacity additions forecast by Portfolio C1 by resource type for each year from 2021 to 2035.

**RESPONSE**: This data has been provided in the Companies' response to ORS AIR 7-2(b). Please Refer to the following files for DEC and DEP, respectively:

ORS AIR 7-2b - DEC New Gen Capital PVRR - Confidential.xlsx
ORS AIR 7-2b - DEP New Gen Capital PVRR - Confidential.xlsx.

9. Separately, for both DEC and DEP, please provide the GWh of generation forecast by Portfolio C1 by resource type for each year from 2021 to 2035.

**RESPONSE**: Please see the attached file: CCEBA DR 1-9 - C1 Generation by Type. This file includes generation by type and year for DEC and DEP separately from Portfolio C1. The results shown in this file reflect the performance of Portfolio C1 in the Companies' base gas price and base CO2 emission price scenario.

CCEBA DR 1-9 - C1
Generation by Type.

10. Do the Companies plan to modify their IRPs as filed in North Carolina to reflect the changes that they made in the Modified IRPs in South Carolina? If not, please include a general discussion of how the Companies will reconcile having two different IRPs for the same system.

**RESPONSE**: The Companies do not plan to modify their 2020 IRPs filed in North Carolina. The Companies do not view the differences between the 2020 IRPs filed in North Carolina and the 2020 SC Modified IRPs as significant. As discussed extensively in the proceeding before the Commission, IRPs are based upon a snapshot in time and the Companies will continue to refine future IRPs to take into account evolving regulatory guidance such as Order No. 2021-447 as well as evolving policy mandates such as NC House Bill 951.

Dated this 18th day of October 2021.


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